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IMPACT OF A SOLAR DOMESTIC HOT WATER DEMAND-SIDE MANAGEMENT PROGRAM ON AN ELECTRIC UTILITY AND ITS CUSTOMERS

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ABSTRACT

A methodology to assess the economic and environmental impacts of a large scale implementation of solar domestic hot water (SDHW) systems is developed. Energy, emission and demand reductions and their respective savings are quantified. It is shown that, on average, an SDHW system provides an energy reduction of about 3200 kWH, avoided emissions of about 2 tons and a capacity contribution of 0.7 kW to a typical Wisconsin utility that installs 5000 SDHW systems. The annual savings from these reductions to utility is \$385,000, providing a return on an investment of over 20%. It is shown that, on average, a consumer will save \$211 annually in hot water heating bills.

1. INTRODUCTION

A large scale implementation of solar energy systems can result in significant economic benefits to both the utility and the homeowner and reduced emission benefits to the environment.

Most utility analyses of solar energy systems stop at an assessment of energy reduction. These assessments are usually based f-chart predictions [1] of monthly performance. This method predicts aggregate energy reduction reasonably well, but it does not identify emission and demand reductions.

Utility analyses that attempt to address the demand reduction achieved by solar options tend to look at the system performance on a single peak day or a group of peak hours. This method fails to account for capacity contribution through demand reductions at all hours [2].

An hourly study of these capacity contributions is needed to accurately assess the improvements in system reliability. Furthermore, operating costs and emission characteristics are dependent on the last plant to be added to the generation mix, known as the marginal plant. Operating costs and emission characteristics are therefore time dependent as the marginal plant varies with time.

An accurate analysis of the impact of solar energy systems must be an annual assessment performed on an hourly basis. The solar system performance is calculated using hourly weather data for the city in which the utility's customers are located. The marginal plant for a given utility or group of utilities is calculated hourly with utility or region load information and plant capacity data for each plant in the regional mix. With hourly predictions of both system performance and the marginal plant, an accurate assessment of energy, emissions and demand reductions can be made.

2. IDENTIFYING COSTS AND BENEFITS

Utilities considering a solar demand side management (DSM) program must identify the potential benefits and costs of the option. Costs related to such a program include the initial investment required to purchase the systems, administrative costs and any operation and maintenance costs that may be associated with the systems. Generally there is no operation costs to the utility associated with solar energy systems as the customers pay for the energy required to run the systems.

Solar energy systems offer benefits such as reductions in energy, emissions and demand. Reductions in energy achieved by SDHW systems at the customer level directly result in these benefits at the generation level. Other benefits may be found in government incentives offered to promote renewable energies. These incentives include tax credits given for capital investment, investment in renewable systems and a subsidy given for renewable energy production.

It is up to the utility to place other values on the program. For example, a utility may include customer retention as a benefit of a solar DSM program. It is possible that an electric utility may lose customers to a natural gas utility. With a solar energy program, a utility may retain a portion of these customers that would otherwise be lost.

Additionally, solar energy programs may bring in new customers, capturing a larger market. Utilities that deal in both electricity and gas may want to consider electric customer retention as a benefit as a higher profit margin is often realized on electricity sales than on natural gas sales.

Utilities may also consider placing value on delayed power plant construction. Solar energy systems effectively add capacity to a utility's generation mix. The effective capacity added by solar energy systems may be significant enough to delay the construction of new facilities and can be viewed as taking further credit for peak demand reduction.

3. SDHW AND EDHW SYSTEM MODELS

To evaluate the impact of a large scale implementation of SDHW systems on an electric utility, knowledge of solar system performance is needed. SDHW and electric domestic hot water (EDHW) systems are modeled with the transient system simulation program TRNSYS [3] developed by the University of Wisconsin Solar Energy Lab. The intent is to represent the results of a large number of simulations with a single simulation.

To simulate a large number of solar energy system with a single system, an average residential hot water draw must be obtained. This average draw may be thought of as the draw seen by a water utility due to residential hot water draws only. Figure 1 shows a typical family of four household water draw as predicted by WATSIM, an EDHW simulation program [4]. Using this water draw as an average water draw would be incorrect as it would represent the water draw patterns of a single household. The water draw depicted in figure 1 is not the average load a water utility would see due to residential hot water draws.

Cragan, et al. [5] addressed the issue of finding an average water draw profile representative of residential hot water draws. Employing WATSIM, nine hundred separate household water draws, as the one shown in figure 1, were simulated. The resulting nine hundred profiles were averaged and smoothed to find average weekday and weekend water draw profiles. Figure 2 shows the resulting average hot water draws that are used to simulate a large number of SDHW and EDHW systems with a single simulation. These draws result in an average draw of approximately 69 gallons/day per household.

Using the average water draw profile shown in figure 2, the average hourly demands of an SDHW and an EDHW system can be accurately predicted [5].

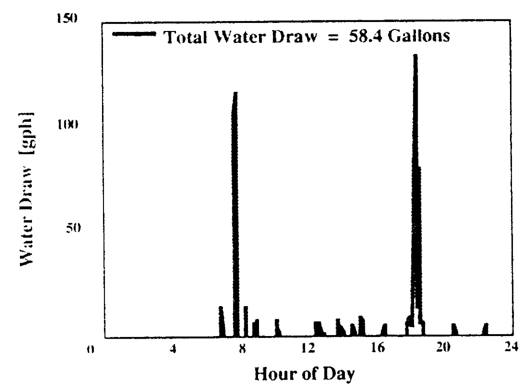

Fig. 1 A typical household daily hot water draw [5]

The SDHW system consists of a collector, auxiliary tank with a 4.5 kW heating element, pump and controller. The heating element in the auxiliary tank provides heat input that is not provided by the solar collector to maintain the upper third of the tank at the set point temperature of 140° F (60° C). The bottom heating element of a conventional EDHW tank is disabled, leaving only the top element. The controller initiates flow through the collector by monitoring the temperatures at the bottom of the tank and at the collector outlet. Table 1 gives the SDHW system parameters used in the simulation.

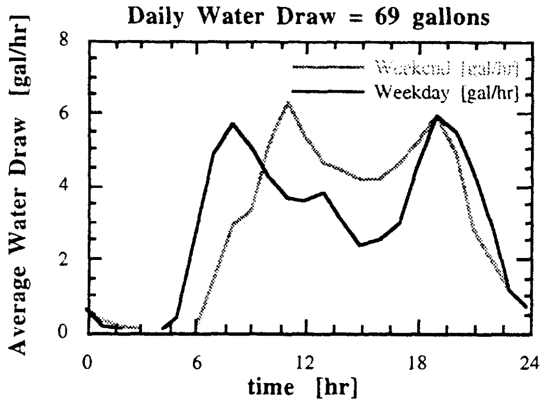

Fig. 2 Average weekday and weekend hot water draw

A standard EDHW system is simulated as a comparative system for the SDHW system. Heating elements are located in the top and bottom thirds of the tank. The heating elements are controlled on a master/slave relationship. With this control, only one element may be on at a given time so that the maximum power demand is 4.5 kW. The EDHW system supplies water at the set point temperature of 140° F (60° C). The EDHW tank has the same parameters as the SDHW tank.

The SDHW and EDHW models are simulated for one year. Figure 3 depicts the yearly demands of the SDHW and EDHW systems. The SDHW demand consists of the auxiliary heat input required to supply hot water at the set point temperature plus the pumping power required to circulate the water through the solar collector. The EDHW system demand consists only of the heat input required to supply hot water at the set point temperature.

TABLE 1: SDHW SYSTEM PARAMETERS

Tank Parameters
 Tank Volume80 [gallons]
 Tank Height4.89 [ft]
 Insulation R Value 16.7 [hr-ft^2-F/Btu]
Solar Collector Parameters
 Area 60 [ft^2]
 $F_R(\tau\alpha)$ 0.70
 F_RU_L0.749 [Btu/hr-ft^2-F]
 Slope23 [degrees]
Pump Parameters
 Pumping power 50 [W]

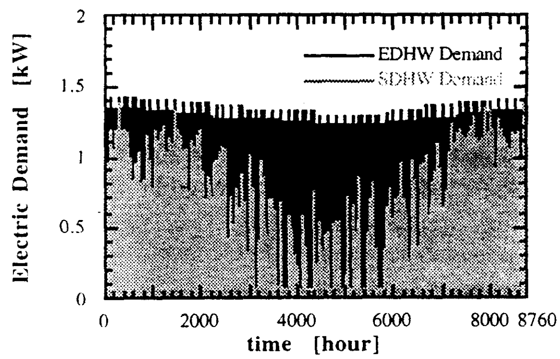

Fig. 3 Average SDHW and EDHW system demands

4. MARGINAL PLANT PREDICTION

The marginal plant must be identified at each hour of the year to correctly assess the energy and emission savings to a utility. Any demand reduction provided by the SDHW ensemble will be seen by the last plant dispatched to meet the load, known as the marginal plant The value of energy saved by an ensemble of SDHW systems is based on the operating cost of the marginal plant. Similarly, the avoided emissions are related to the emission characteristics of the marginal plant. Utility electric generating plants face forced and scheduled outages during their operation. In order to predict the marginal plant, a methodology is set up to adjust the capacity to account for these outages. The year is broken down into two general seasons, a peak season and a maintenance season. For example, the maintenance seasons may be defined as the spring and fall months when the load is relatively low. The peak seasons then are the winter and summer months when utilities tend to find relatively higher demands. During the peak season, the capacity is adjusted to account for forced outages only. In the maintenance season, the plant capacity is adjusted to account for forced and scheduled outages.

To adjust the nameplate capacity for forced outages, a forced outage adjustment factor is first calculated (FOA factor). The FOA factor is calculated with forced outage and capacity information. The FOA factor is defined in equation 1.

$$\text{FOA factor} = 1 - \text{fullout} - \sum_{i=1}^{4} \frac{\text{partout}_i * \text{partcap}_i}{\text{Capacity}} \qquad (1)$$

In this equation, fullout and partout are historical fractions of time in which a generating unit experiences full and partial outages respectively. The variable partcap is the remaining capacity that is available for service in the case of a partial outage. It is not the amount of capacity that is lost during the partial outage. The FOA factor is used with the nameplate capacity of the plant to calculate the forced outage adjusted capacity (FOA capacity) as defined in equation 2.

$$\text{FOA capacity} = \text{FOA factor} * \text{Capacity} \tag{2}$$

The FOA capacity is an effective capacity used to find the marginal plant during times when the plant is assumed to be operating in the peak season.

In addition to adjusting plant capacity for forced outages, capacity also needs to be adjusted for scheduled outages. At times a utility knows exactly when it will take a plant off line. When this is the case, the scheduled outage information can be entered to make the forced and scheduled outage capacity (FSOA capacity) zero. However, there are times when a utility may know only a given time frame in which a plant will be off line. If this is the case, the FSOA capacity has a value and the effective plant capacity is a fraction of its nameplate capacity. This type of adjustment particularly makes sense when looking at a region of utilities in which case it is hard to identify when neighboring utilities will take their plants off line.

To adjust the capacity to account for scheduled outages, scheduled outage information is needed to calculate a scheduled outage adjustment factor (SOA factor). The information required includes the scheduled outage, actual amount of time that a plant is taken off line during the year, and the duration of the maintenance period. Equation 3 defines the SOA factor.

$$\text{SOA factor} = 1 - \frac{\text{scheduled outage}}{\text{outage period}} \tag{3}$$

The outage period is the range of time that the scheduled outage could occur in. Note that by making the outage period equal to the scheduled outage the SOA factor goes to zero. Thus, if a utility knows exactly when a plant is to be off line it can be reflected with a forced and scheduled outage capacity of zero. Equation 4 shows the calculation of the FSOA capacity.

$$\text{FSOA capacity} = \text{SOA factor} * \text{FOA capacity} \tag{4}$$

Note that the FSOA capacity is based on the capacity previously adjusted for forced outages. This adjustment is to account for the possibility of a forced outage during the maintenance period.

Figure 4 shows the load and effective capacities for a utility region consisting of Wisconsin Electric Power Company (WEPCO), Wisconsin Public Service Corporation (WPS), Wisconsin Power and Light Company (WPL), Madison Gas and Electric (MG&E), Northern States Power Company (NSP) and Dairyland Power Cooperative (DPC). The maintenance periods are defined as March 1 through May 1 for spring and September 20 through November 20 for fall. Defining a utility region accounts for energy and capacity sales between utilities in the defined region.

To determine the marginal plants, the adjusted capacity of the individual generating units of each utility is added to the generation mix on a least cost basis until the load is met. By identifying the marginal plant at each hour of the year, the marginal operating costs and emission characteristics are known. Figure 5 shows the predicted marginal operating costs for the defined region of utilities.

5. ASSESSMENT OF ENERGY, EMISSION AND DEMAND REDUCTION BENEFITS

To assess the reduction in electricity that needs to be generated by the power plants, the hourly system performance, defined as the EDHW demand minus the SDHW demand, is scaled by the number of installed solar systems and passed back through the distribution and transmission system. Equation 5 defines the reduction in power generation requirements. By summing the hourly

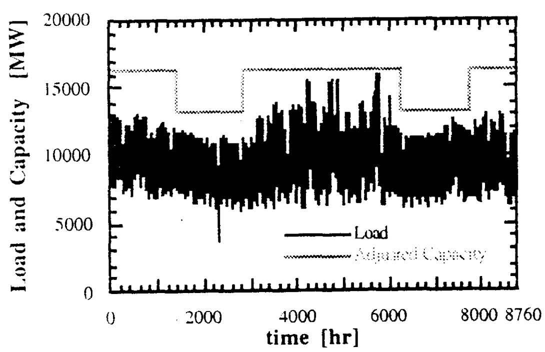

Fig. 4 Regional load and adjusted capacities

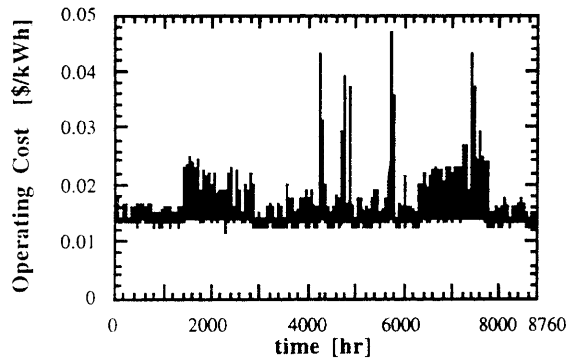

Fig 5 Regional marginal operating costs

reduction values over the year, energy reduction is obtained.

$$P_{reduction,\ generation} = \frac{N_{systems} * P_{system}}{(1 - Loss_{distribution}) * (1 - Loss_{transmission})} \tag{5}$$

where: $P_{system} = P_{EDHW} - P_{SDHW}$

With methodologies to obtain the amount of avoided power production at the generation level and the marginal plant at each hour of the year, the total savings at the generation level can be assessed in terms of dollars. The operating cost of the marginal plant is used to assess the savings in terms of dollars at each hour. These savings are then summed over the year to give the annual energy savings.

The total avoided emissions are directly related to the energy reduction at the generation level and the marginal plant. Any reduction in energy generation reduces emissions in proportion to the emission characteristics of the marginal plant. The annual emission reduction is found by summing the hourly emission reductions over the year.

The value of reducing an emission will vary among utilities. In some areas utilities must buy credits to emit a certain pollutant. This purchase is a real cost to a utility and thus, reducing emissions has value. Other value that may be placed on avoided emissions might include the cost of equipment that would be needed to handle the emission such as scrubbers or baghouses.

The peak hour method and capacity contribution index method are two methods commonly used to assess capacity contribution due to demand reductions [7]. The former method assesses demand reduction as the avoided generation at a single peak load hour or as the average demand reduction for a specified number of hours with highest loads. The CCI method assesses demand contributions over the entire year, weighted by the marginal expected unserved energy (EUE) [2]. In either case, capacity contributions are related to the reduction in generation requirements at times when the utility is under heavy stress. Figure 6 shows the average demands of both an EDHW and an SDHW system and the system load on the day of the regional peak load.

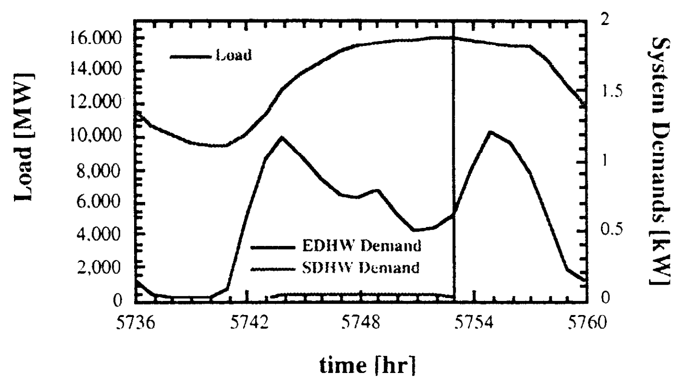

Fig 6 Average EDHW and SDHW system demands on day of peak load

The value of reducing demand is identified in three areas. Demand reduction has value at the generation level as it reduces capacity and reserve requirements. Demand reduction is also beneficial to the transmission and distribution systems since it lessens their capacity requirements. The avoided costs of meeting the capacity needs has value to generation, transmission and distribution systems.

The value of reducing capacity requirements at the generation level is based relative to the cost per kW of meeting the capacity needs with a conventional option. A combustion turbine is commonly used to supply peak loads due to its low initial cost relative to a coal or nuclear power plant. The value to transmission and distribution systems due to demand reductions are found in a similar manner. The cost used in assessing the value of reducing capacity requirements is the cost per kW for each system to add sufficient facilities and equipment to supply the demand.

6. ECONOMIC ANALYSIS

The preliminary step in performing an economic analysis of a solar DSM is to define the necessary economic parameters. The required economic parameters to be used in the analysis are the appropriate inflation rate (inf), discount rate (dis) and economic life of the solar energy system (N_{life}). The time and frequency of occurrence of the cash flows associated with the costs and benefits and other economic considerations of the option must be identified to determine the present worth of the life cycle savings of a solar energy resource. Other economic considerations identified are the depreciation of the solar equipment and the downpayments and lease payments made by the customer.

The cash flows are categorized by their occurrence and how they are handled in the economic calculation. Equation 6 gives the present worth of the life cycle savings of a solar energy option relative to a conventional option.

$$LCS_{PW} = A + B*PWF(N_{life},inf,dis) + C*PWF(N_{life},0,dis) + D*PWF(N_{depreciation},0,dis) \quad (6)$$

where:

A = -Investment + Tax Credit + Demand Value + DelayValue + Retention Value + Downpayments
B = Energy Savings + Total Emission Savings + Subsidy - OM&A
C = Lease Payments (monthly lease payment *12)
D = Depreciation
inf = inflation rate
dis = discount rate
N_{life} = economic life of solar energy system
$N_{depreciation}$ = depreciation years

The parameters that make up the A term in equation 6 are credited for a time zero. The investment and associated government tax credit and customer downpayments are assumed to occur immediately. The value of demand is given as the cost in present dollars of an option that would supply an equivalent amount of demand that is provided by the solar energy systems. A common example of such an option is a combustion turbine. Similarly, delaying the construction of new facilities is credited for in present worth dollars. This term accounts for any additional value of demand reduction beyond capacity contributions such as the ability to invest money that would be needed to pay for the new facilities. Customer retention is also credited for at time zero in terms of present worth dollars.

The series of benefits that make up the B term in equation 6 are brought back to present time with the present worth factor, PWF, using the parameters N_{life}, inf and dis [1].

The series of lease payments (term C) are brought back to present value using $PWF(N_{life},0,dis)$, the present worth factor. The economic calculation is simplified by assuming that the utility sees an annual lease payment rather than monthly payments. It is assumed that the customer will pay the same monthly payment over the life of the program. That is, the lease payment does not inflate.

The solar energy equipment is can be depreciated if the utility retains ownership. The equipment may be depreciated over a separate life span ($N_{depreciation}$). Straight line depreciation is assumed for model simplicity. The depreciation factor D is the investment times the utility tax bracket divided by the depreciation years, $N_{depreciation}$

With the present worth of the life cycle savings calculated, the levelized savings of the option can be found using equation 8. The levelized savings of an option is the uniform series of payments that the utility would see over the life of the option. In other words, it is the uniform series of income with no inflation that equals the present worth of the life cycle savings.

$$LCS_{Levelized} = \frac{LCS_{PW}}{PWF(N_{life},0,d)} \quad (8)$$

The rate of return (ROR) of the option is the discount rate that makes the present worth of the life cycle savings (equation 6) equal to zero. Equation 6 is solved numerically to find the rate of return.

7. CASE STUDY

The software package EUSESIA, An Electric Utility Solar Energy System Impact Analysis [8] is used in a case study. EUSESIA employs the models and equations developed to this point to automate the analysis of the impact of an ensemble of SDHW systems on an electric utility. EUSESIA is broken down into three general areas of analysis: solar energy and conventional system analysis, marginal plant analysis and economic and environmental impact analysis. The impact of an ensemble of SDHW systems is assessed for WEPCO. The analysis is based on 5000 SDHW systems.

The analysis includes payments made by the customer for the solar energy systems. For example, a program by WPS offers the solar systems to the customer for $140 down and a $12 per month lease. The installed cost of a single solar energy system is $2000. The utility is assumed to maintain ownership of the systems so that they may be depreciated. The depreciation period chosen is five years.

A utility may have reasons to credit emissions with a certain value. SO_2 has real value as WEPCO must buy credits to emit SO_2. The value assigned to SO_2 is $0.02/lbm. No other emissions are credited for in this analysis.

The CCI method is used to evaluate demand reduction. Capacity contributions at the generation level are valued relative to a combustion turbine. The present worth value of capacity contribution is given to be $325/kW. Transmission and distribution capacity contributions are each given a present worth value of $100/kW. Thus, the cost of adding an additional kW of capacity is $425/kW.

Customer retention and delayed power plant construction are not credited for in this analysis. Government incentives, however are included as benefits of the solar program. A ten percent tax credit is given for the initial investment in purchasing the solar energy systems.

The economic parameters are chosen to best represent WEPCO. The economic life of the SDHW systems is given as 20 years. An inflation rate of 5% and a discount rate of 8% are used in the economic calculations. The utility is assumed to be in the 34% taxbracket. Figure 7 shows the outputs from the EUSESIA analysis.

The present worth of the life cycle savings for the SDHW option is around 6.3 million dollars. Levelized, the life cycle savings are $641,400 per year. The rate of return of the SDHW ensemble is 21.2%. A similar analysis excluding the customer lease payments and including only the cost of the systems, operation and maintenance costs and the energy, emission and demand savings results in a rate of return of 2.8%. Obviously the utility can adjust the rate of return by adjusting the lease agreement.

The system performance summary gives results of interest to a typical customer. The energy requirements of the EDHW and SDHW systems and their difference are given on a monthly basis. The annual solar fraction (SF) of the SDHW system is defined to be the difference in the EDHW and SDHW energy requirements divided by the EDHW energy requirement. The solar fraction is found to be 0.56. The monthly savings are reported using a summer rate of $0.0745/kWh for the months June though September and a winter rate of $0.064/kWh for the remaining months as typical consumer electric rates. The annual energy savings to a customer is $211.

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Electric Utility Solar Energy System Impact Analysis:

Impact of a Large Scale Implementation of a Solar Energy System
on an Electric Utility

** Energy and Environmental Impact Summary for the First Year ******
Results based on: 5000 solar systems

              Energy Reduction (kWh)          Energy Savings ($)
                  16090000                        261300

              Emission Reduction (lbm)        Emission Value ($)
      CO2         18860000                           0
      SO2           139700                        2793
      NOX            92770                           0
      N2O              298                           0
    Parts             7961                           0
      CH4              184                           0
       HG                0                           0
   INTKES                0                           0
                                                  2793

              Demand Reduction (kW)           Demand Savings ($)
                   3529                           121200

                                              Total Savings ($)
                                                  385292

** Economic Analysis Summary ******************************************

Present Worth of Investment                  - $ 10000000
Present Worth of OM&A                        - $   717900
Present Worth of Energy Savings                $  3751000
Present Worth of Emission Savings              $    40110
Present Worth of Demand Savings                $  1740000
Present Worth of Depreciation                  $  2715000
Present Worth of Downpayments                  $   700000
Present Worth of Lease Payments                $  7069000
Present Worth of Tax Credit                    $  1000000
Present Worth of Energy Subsidy                $        0
Present Worth of Customer Retention            $        0
Present Worth of Delay Value                   $        0

Present Worth of Life Cycle Savings            $  6297000
Levelized Savings of Option                    $   641400
Rate of Return of Option                            21.2 %

** System Performance Summary and Customer Savings ********************
Results based on average system performance

        Eic (kWh)   Sol (kWh)   Del (kWh)   SF    Savings ($)
  JAN     489         357         132      .269      8.43
  FEB     437         262         174      .399     11.16
  MAR     477         256         221      .463     14.13
  APR     449         157         293      .651     18.73
  MAY     459         114         345      .753     22.09
  JUN     439          40         399      .909     29.69
  JUL     444          51         393      .885     29.27
  AUG     444          73         371      .837     27.55
  SEP     442         135         307      .695     22.87
  OCT     463         252         212      .457     13.55
  NOV     458         352         106      .230      6.75
  DEC     479         370         109      .227      6.95

  YEAR   5477        2417        3060      .559    211.28
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Fig. 7 Output from the EUSESIA Analysis

8. CONCLUSIONS

A large scale implementation of solar energy systems has significant impact on an electric utility. On average, an SDHW system consisting of a 60 ft^2 collector and a single 80 gallon tank realizes annual energy reductions at the utility level of 3218 kWh, emission reductions of: 3772 lbm CO_2, 27.9 lbm SO_2, 18.6 lbm NO_X, 0.0596 lbm N_2O, 1.6 lbm particulates and 0.0368 lbm CH_4 and demand reduction of 0.71 kW.

The annual savings resulting from an ensemble of 5000 SDHW systems are $261,300 in energy reduction, $2,793 in emission reduction and $121,200 in demand reduction. The

economic value of the emission savings are negligible compared to the energy and demand savings, but may be more substantial in the future as emission regulations become tougher.
An economic analysis shows a rate of investment of about 3% when the utility loans the SDHW system to the customer for free and considers only the energy, emission and demand savings and the costs of the systems and annual operation and maintenance costs. When customer lease payments, are included along with depreciation and government incentives the rate of investment exceeds 20%. The results of economic analysis are dependent on the benefits for which the utility takes credit and "green pricing" is a utility option.

An annual analysis performed on an hourly basis is required to accurately assess the impact of an ensemble of solar energy systems on an electric utility. Energy savings and emission reduction are dependent on the operating costs and emission characteristics of the marginal plant, which varies hourly. Hourly weather and load data from the same year must be supplied to accurately assess the demand reduction of an ensemble of solar energy systems.

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